

2001 ANNUAL REPORT



Annual General Meeting

The Annual General Meeting of the Shareholders of Stampede Oils Inc. is to be held at 2:30 p.m. on Thursday, August 1, 2002, in the Eau Claire Room of the Westin Calgary, 320 - 4th Avenue S.W., Calgary, Alberta.

COVER:

Stampede Turner Valley
2-34-20-3 W5M
Workover

Report to the Shareholders

At the time of writing this Report to the Shareholders, the Company's main exploration/development project for the past two years, the Stampede Turner Valley 2-34-20-3 W5M well, is currently exhibiting very positive evidence of finally coming into a sustained oil production mode.

Subsequent to the installation of an approximate 450m (1,475 ft.) three-inch flow line from this 2-34 oil discovery well into the nearby Devon Canada Corporation Turner Valley pipeline system, the well was subjected to a final wellbore cleanup operation commencing on April 5th. The performance of the well at that time indicated that it should definitely be able to reach ultimately, the expected production rate of 1,000 barrels per day, as previously forecast, despite the fact that a significant amount of load water with CaCO₃ plugging material, that had been injected into the reservoir without the Company's knowledge, was still to be recovered.

At the time of writing the Report to the Shareholders for last year's 2000 Annual Report, reference was made that **"Despite continued objector efforts to not allow this well to be tested, which included an operation suspension of the well last December, the 2-34 well at the time of this writing is in the wellbore cleanup stage, preparatory to production testing."** Incredibly, as stated above, at the time of writing this year's Report to the Shareholders, the near reservoir wellbore cleanup operation of the 2-34 well still has not been fully completed. Prior to the last EUB suspension on July 18, 2001, wellbore cleanup operations had progressed to the state where it was apparent that a large part of the load fluid in the reservoir had been recovered. During the wellbore cleanup, the impeded flow rate has necessitated pump assistance to facilitate recovery of the remaining load fluid and it is expected that during the first days of oil production that the flow rate may necessitate pump assistance to facilitate recovery of the remaining load fluid and CaCO₃, but this should not prevail for too long a period.

In mid April it became obvious that although the remaining load fluid problem in the reservoir was diminishing, the downhole pump was apparently malfunctioning. The downhole pump was retrieved on Sunday, May 19th at which time it was determined that it was impacted and seized up with CaCO₃ from the 1.5 tons of this plugging material that had been injected into the reservoir shortly after the well reached total depth on November 10, 2000. A new downhole pump has been put in the well, the design of which prevents the plugging that the first downhole pump experienced. The fluid/gas recovery response to this new downhole pump has been very positive.

As the final wellbore cleanup of the 2-34 well commenced on April 5, 2002, 513 days (approximately 1.4 years) after this well was drilled to total depth in the early hours of November 10, 2000, it is appropriate at this time to provide shareholders with a chronology of some of the pertinent events that contributed to this incredible delay period.

Chronology of Events

1. November 5, 2000 - Well drilled to casing point at a measured depth of 3128.2 metres, at the top of the primary target zone, the Regional Turner Valley formation.
2. November 7, 2000 - Casing cemented with 69 feet of cement remaining inside the lower casing.
3. November 8 & 9, 2000 - The Turner Valley reservoir was drilled into using only water and a polymer additive to enable drill cuttings to be carried out of the hole to surface.
4. The polymer additive was not the one represented to Stampede by its consulting engineers and agents, but one that would begin cross linking (setting up/hardening) upon exposure to free calcium and a PH of 11.
5. The drill out operation entailed drilling through the 69 feet of cement in the base of the casing before drilling into the Turner Valley reservoir. This phase of drilling through fresh cement provided the source for free calcium needed to trigger the cross linking of the polymer additive in the drilling fluid and thereby introducing an initial plug into the wellbore.
6. November 10, 2000 - Well drilled to total depth at approximately 1:30 a.m.

7. The drill penetration rate into the Regional Turner Valley formation was exceedingly fast. The indicated excellent quality of the reservoir was substantiated by the lithology characteristics in the drill cuttings, along with the very positive indications of oil saturation.
8. Unknown to Stampede, the drilling representative for the Company's consulting drilling engineering firm at that time, approximately two hours after total depth had been reached and the bottom hole samples circulated to surface, on November 10th, had 1.5 tons of 325-mesh CaCO₃ injected into the reservoir over an approximate two hour period. The consistency of 325-mesh is finer than that of talcum powder. This operation was misrepresented in the rig tour sheet for that day.
9. November 12, 2000 - A permanent packer was set in the base of the casing, above the open hole in the Turner Valley reservoir and a tubing string latched into it. The placing of a permanent packer in the casing rather than a retrievable packer effectively nullified several operational options Stampede intended to have available to it, by conducting an open hole completion in the target Regional Turner Valley reservoir.
10. Unknown to Stampede at the time, disposal fluid from a nearby gas well testing operation was trucked to and put into the 2-34 well. Contrary to good oilfield practice, the tubing string was anchored into the packer without having inhibited fluid injected into the annulus, and it was eventually determined that the annulus contained Elkton and Turner Valley reservoir disposal fluid from the other well. The use of this corrosive water from one well into another without EUB approval is contrary to oil and gas regulations. Stampede was first made aware of this disposal fluid situation in mid December 2000 when the representative from the consulting engineering firm advised, at an Appropriate Dispute Resolution meeting pertaining to a different well, that this had been done. The company conducting a gas testing operation in the nearby well had paid the trucking costs.
11. The principal of Stampede's consulting engineering firm gave notice by way of a letter dated October 27, 2000 that this company would be terminating its involvement in the 2-34 operations on November 21st. It became apparent later that the probable reason for this resignation as Stampede's consultant, halfway through the total project, was that it would be knowledgeable of how difficult it was going to be to complete and have this well put into production.
12. November 15 & 16, 2000 - An attempt was made to test the 2-34 well but it became obvious that for some reason there was not any fluid entry into the wellbore from the Turner Valley reservoir. At this time Stampede had no knowledge of the polymer and CaCO₃ plugging problem. A very limited acid job was conducted with only a minor amount of success. The well was temporarily suspended in order to consider and evaluate the problem and assess available remedial options.
13. The preceding consulting engineering firm dissertation represents only a few of many identified very questionable operational procedures conducted by this firm during its overall involvement in the 2-34 well. It should be denoted here that prior to the EUB Section 42 hearing being conducted, Stampede was forced into a Settlement Agreement with the consulting engineering firm wherein it had to agree not to sue this firm for any of its activities related to the 2-34 well operations, otherwise Stampede was on notice that they would join with the objectors to attempt to prevent the well from being completed. Stampede subsequently did not pay the last two invoices from this firm due to the gross negligence involved and are now being sued for this unpaid amount of approximately \$43,000.00. The defense by Stampede has incorporated an offset amount in excess of \$2.5 million in excess costs and damages. Stampede is currently having the validity of the Settlement Agreement assessed.
14. December 9, 2000 - An attempt to initiate an open hole perforating operation to remedy the now identified polymer wellbore plugging situation commenced. A very minor amount of solution gas was bled off and vented on a restricted basis for the first half hour at which time oil flowed to surface. The well was immediately shut-in. Attempts to open hole perforate during that day were not successful and minor venting of associated equipment with an approximate 5-10 minute restricted burn of vented gas was conducted twice throughout the rest of the day until the well was shut-in at 5:00 p.m.
15. December 10, 2000 - After the November 21st date of the consulting engineers' termination in the 2-34 well operations, the same field drilling representative was still retained for the completion of the well. This termination unfortunately resulted in a late notification to residents of the Company's perforating operations commencing on December 10th. The notice was sent out subsequently on December 12th, two days late.

This oversight, along with a complaint by a resident living 1.25 miles east of the well resulted in the Company receiving a verbal suspension of operations order at approximately 8:00 p.m. on Saturday evening. The resident claimed that Stampede was flaring gas early in the evening even though the master valve on the wellhead had been closed since 5:00 p.m. that day.

16. The above suspension was lifted the next afternoon by way of a verbal directive from the EUB field office and the operator resumed the perforating operations on the morning of Monday, December 12th. It was able to conduct one successful five-metre perforation run over the lower interval in the open hole when it received another verbal directive from the main office of the EUB to once again suspend operations.

Though Stampede had committed to not have any flaring of formation gas during testing and production operations, the fact that it had conducted very minor flaring of vented gas during the preliminary completion operation and not during any testing or production operation was, however, deemed to be a breach of the above no-flaring commitment.

17. January 17, 2001 - This suspension No. 1 was lifted, but as test and downhole cleanup equipment was not readily available, the 2-34 wellbore cleanup operation was not able to re-commence until February 28th.
18. March 4, 2001 - The well was opened to flow on March 4, 2001 at which time it flowed approximately 30 barrels of oil to surface and then died. A subsequent perforating operation to get through the polymer wellbore blockage encountered approximately 10 metres (32 feet) of CaCO₃ fill in the bottom of the wellbore, which had come out of the bottom five foot perforated interval in the reservoir.
19. The rest of the reservoir section in the open hole was perforated and the wellbore then subjected to a swabbing operation as part of the near reservoir wellbore cleanup. A combination of oil and varying amounts of load water were recovered prior to the discovery of a perforation in the tubing. A single joint of tubing with a hole in it was located and replaced, along with 41 other joints of tubing that had been badly damaged by over-torquing when the tubing was run into the hole. The water recovered was determined to have been fluid in the annulus and it was apparent that a remedial operation to eliminate the now identified CaCO₃ plugging in the near wellbore area of the reservoir was necessary. A determination from the mud company records showed that a 1.5-ton CaCO₃ plug had been injected into the reservoir earlier by the consulting engineering firm representative.
20. The reservoir was subjected to a fairly extensive acid squeeze to eliminate as much of the CaCO₃ in the reservoir as possible.
21. On April 4th at approximately 9:30 a.m. during the initial flow-back of acid load water, a very minute amount of H₂S was detected in the nitrogen recovery flow-back stream which would probably not be incinerated properly at the time. The well was shut-in immediately in order to make necessary adjustments for more adequate combustion in the incinerator unit. Approximately 1¼ hours later an emission was detected by the Company's roving monitor unit approximately one mile north of the well. This reading averaged 4 PPB over a one-hour period, well below the EUB Alert & Reporting threshold of 10 PPB averaged over a one-hour period.

There was not any off-lease odour as the threshold level for detecting the odour of H₂S varies from 30-40 PPB.

Though there was not any actual off-lease odour related to this incident, an area resident approximately one-half mile away reported to the EUB two days later that such an incident occurred late in the afternoon on April 4th. The EUB initiated suspension No. 2 on April 12th as a direct result of this reported incident.

22. The No. 2 EUB suspension was lifted on April 19th subsequent to which the well cleanup swabbing operation was recommenced in order to recover approximately 177 m³ (1,113 barrels) of load fluid calculated to have been used in the injection of the CaCO₃ plug into the reservoir.
23. In early July the cleanup operation was finally experiencing positive, recoveries with the utilization of a downhole pump when Stampede was directed by the EUB that it must finish the current operation no later than Saturday, July 14th and then initiate its planned five-day inline cleanup operation.

Though the well response at this time was increasingly positive, Stampede considered the inline startup date premature by about one week. However, it was informed operations would be suspended if the directive to commence inline flowing was not adhered to. The activities necessitated to comply with this premature and unexpected directive to ready all facilities for the inline operation unfortunately resulted in the expiry date of the necessary temporary pipeline permit not being checked.

It should be noted here that unknown to Stampede, the prior consulting firm engineering representative who applied for this temporary pipeline permit in early November, 2000 only applied for a three-month permit rather than the usual maximum one-year permit. The permit was issued in late November with essentially only two months left and at this time this engineering firm had not even initiated negotiations with the third party entity for agreement to tie the temporary pipeline into their facilities. Lead time for such an agreement to be put into place would be approximately two months.

24. The temporary inline cleanup/test operation had been planned for only a five-day period. The oil recovery response during the first three days of this operation was very positive having gone from an average oil content recovery of 20% the first day to 52% by the third day. However, in the morning of the fourth day on July 18th, the operation was once again suspended by the EUB as it had been determined that the permit for the temporary surface pipeline had expired.

Shortly thereafter the EUB directed that a Section 42 hearing would be held as a result of a resident application for such a hearing in December of 2000 coupled with the three previously discussed suspensions related to the 2-34 well operation to date.

The hearing commenced on October 2, 2001 and finished on October 10th. Subsequently, it appears that the EUB's stated policy of fairness and impartiality to all prevailed, as the Decision issued on December 20, 2001 gave Stampede the right to complete the well, in the public interest, subject to certain conditions. These included the submission to the EUB of a Strategic and Tactical Plan regarding public consultation, such plan to be approved by the EUB prior to the suspension of operations being lifted from the 2-34 well.

Considerable thought and planning went into the formulization of this plan and it was finally submitted to the EUB on January 29th. Subsequent to two EUB clarification directives final approval by the EUB was forthcoming on March 13th. The actual flowline construction operation to tie the 2-34 well into the nearby gathering system facilities, could not commence until March 21st.

As of the date of this Report to the Shareholders, the production stage for the 2-34 well, expected to commence on April 5th has been further set back by the necessity for recovering the remaining CaCO₃ load fluid out of the reservoir and wellbore. Though it appeared that in mid April the remaining CaCO₃ load fluid was minimal, there were also indications that the downhole pump was malfunctioning. Subsequent retrieval and inspection of this pump on May 19th, evidenced that it was seized solid by CaCO₃ impacting. Analysis of fluid recovery samples through the month of April demonstrated a very high concentration of CaCO₃ (82%-98%) in the residue. The initial days of production from the 2-34 well are expected to require some downhole pump assistance until the remnants of the CaCO₃ load water are fully recovered, after at which it should ultimately increase production capacity as a very significant flowing oil well.

The preceding difficulties and related delay of the completion of the Stampede Turner Valley 2-34-20-3 W5M well for production entailed an excessive cost burden to the Company, as reflected in the accompanying financial statements. The original Authority for Expenditure for the drilling of the well was \$3.2 million (Can.) whereas the final overall cost is now approximately \$8.5 million. Stampede and working interest partners intend to initiate proceedings in the future for commensurate retribution.

This lengthy period of delay for having this well put on production also served to discredit the status of this 2-34 oil discovery well, the related operations and working interest participants. This did serve to make subsequent financing endeavours difficult.

Stampede has implemented procedures regarding the contracting of consulting services wherein the accountability for operational procedures will be monitored on a continuing basis.

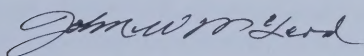
The Company expresses sincere regret to all shareholders for the incredible period of delay in having the 2-34 discovery well put into production. On the positive side, the reservoir quality of this discovery well and ramifications of substantiating a major bypassed oil pool in the deeper Regional Turner Valley reservoir will more

than compensate in the long run for all the anguish and frustration the Company and its shareholders have endured this past year. This well, along with the IMP Berkley Turner Valley 8-21-21-3 W5M and Anadarko's BPC et al Turner Valley 10-16-21-3 W5M wells four miles to the north, both of which are completed in the gas cap of this bypassed oil pool, are the vanguards to what should become a major development drilling program. Wellbore data from two recently drilled wells approximately eight miles north of the 2-34 well, further substantiate the interpretation and delineation of this major bypassed oil pool.

The Board of Directors expresses its sincere appreciation to all Stampede shareholders for the patience expressed to date, without which the road would have been much rougher. Your continuing support is again requested to help ensure the escalation of Stampede's value through the necessary ongoing development of recoverable oil reserves in this major bypassed pool.

We look forward to seeing as many of you as possible at the Annual General Meeting.

On Behalf of the Board of Directors



John W. McLeod

President

June 7, 2002

OIL & GAS OPERATIONS

A. ENVIRONMENTAL

With regard to the emphasis now being placed on legitimate environmental concerns related to overall industry oil and gas operations, the Company considers that a brief discussion regarding Stampede's environmental policies is warranted.

Regulatory obligations related to oil and gas wellsite operations are set out in the Alberta Oil and Gas Conservation Act and the Environmental Protection and Enhancement Act. The Alberta Energy and Utilities Board is responsible for enforcing and ensuring environmental protection concerning oil and gas operations.

Stampede has a high degree of concern regarding any possible effects from its exploration and development drilling operations including, but not limited to, community health and safety, soil disturbances, waste removal and continuing air quality. Measures are always in place to be able to anticipate, identify, address, prevent and/or control possible adverse environmental effects that may pertain to any Company operations.

Stampede et al adhere to industry-accepted operating practices and comply with all related government regulations. Industry-wide assessments demonstrate an extremely low possibility of any event which might produce a negative impact on the environment, provided regulatory and industry policies are met or exceeded. All Company operations have contingency plans to deal with any such unlikely event.

As part of its efforts to ensure that the Company's operations address environmental issues satisfactorily, Stampede and partners have utilized a sumplex mud system in its Turner Valley operations. This system incorporates a centrifuge facility that provides for the separation of drill cuttings from the mud system and the subsequent continual recycling of the water/mud column in the wellbore.

Testing operations for a sour gas well dictate the employment of mobile monitoring units to ensure against the leakage of H₂S and the adequate dispersion of flaring emissions in accordance with EUB approved standards.

A newly developing incineration process is now available as an alternative to the use of flare stacks. In an area where there may be access to adequate pipeline facilities, utilizing in-line production procedures will also be given serious consideration. Stampede et al will install downhole safety shut-off valves in sour gas wells completed in areas having nearby residences.

Stampede will communicate on a continuing basis with all possibly affected local communities and other stakeholders related to its operations, incorporating a newly developed public consultation program.

B. TURNER VALLEY NORTH PROJECT

The main target horizon in Turner Valley North is interpreted to be a large deep continuous anticlinal structure, indicated to contain a major oil pool in the Regional Mississippian Turner Valley formation at a depth of approximately 3048 metres (10,000 feet). From November 29, 1993 to March 4, 1995 Stampede and partners conducted a preliminary deep drilling exploration program with regard to this interpreted major 37 km (23 miles) long deep anticlinal structure that generally underlies and is adjacent to the current/historic Turner Valley field and associated overthrust fault blocks.

The results of this preliminary exploration evaluation drilling program necessitated an extensive follow-up data research program with interpretive fine-tuning. Stampede et al then arranged to have two companies join in the project with the drilling of two follow-up wells. The results of these two wells, along with the results of previous wells, have substantiated the related overall structural and hydrocarbon interpretation. The IMP Berkley Turner Valley 8-21-21-3 W5M well has established an indicated gas/oil contact at approximately -1798m subsea while 9.6 km (6 miles) to the south, the currently suspended Stampede Bcat et al TV 6-23-20-3 W5M well has identified an oil/water contact at approximately -1920m subsea. The recently drilled and completed Berkley (Anadarko) 10-16-21-3 W5M well, offsetting the IMP 8-21 well 1.6 km (1 mile) to the south, is completed in the gas cap of this Regional Turner Valley oil pool. This deep Regional Mississippian Turner Valley oil pool is indicated to have an approximate 122m (400 ft.) vertical oil leg.

Both the IMP 8-21 and the Anadarko 10-16 wells were put into production late last year. Current reports indicate that both wells have had to be choked back considerably to minimize oil entry and are producing at very high surface flowing pressures. Reliable information regarding related oil production for these two wells is not yet available.

The deep Regional anticlinal structural feature is not subject to disruptive and abrupt geological changes as experienced in the more shallow, heavily faulted and fractured overthrust zones. The lateral continuity of structure in this deeper horizon is expected and is able to be projected geologically. The amount of pertinent good quality seismic control, coupled with very good strategically located subsurface wellbore data, supports and endorses the determined overall structural interpretation.

Recoverable reserves of 39.6° – 47° gravity oil are indicated to be in excess of 500 million barrels. Recoverable gas reserves are interpreted to be in excess of three (3) trillion cubic feet (TCF). Wells are expected to be capable of production rates in excess of 500 barrels of oil per day and gas wells completed in the deeper Devonian Crossfield reservoir to the northeast should be capable of in excess of 10 million cubic feet (mmcf) per day.

C. OIL/GAS WELLS (CURRENT AND FUTURE)

TURNER VALLEY NORTH

Current Operations

1. Stampede Turner Valley 2-34-20-3 W5M (24.86% interest)

Regional Turner Valley main oil pool, 80 feet net pay. Detailed discussion contained in Report to the Shareholders. Technical wellbore test data indicates this well is capable of oil production flow rate of at least 1,000 barrels per day.

2. IMP Berkley Turner Valley 8-21-21-3 W5M (5.56%-18.6% interest)

Imperial Oil Resources, the current operator of this well finally put it into production on November 29, 2001. It is reported that the remaining non-recovered acid load water and mud filtrate that finally came out of the reservoir subsequent to production startup, caused significant difficulties at the Quirk Creek gas plant for a 10-day period.

The Company is also under advisement that an increasing amount of oil recovery has necessitated the gas production from this well to be choked back very significantly to reduce the increasing production of 45° – 47° gravity oil.

The Company's interpretation of the deep Regional Turner Valley reservoir has determined potential for in excess of 500 million barrels of recoverable oil ranging from 39.6° to 47° gravity with 20% primary and 30% secondary recovery factors. The gas cap for this formation is indicated to be in excess of one TCF of recoverable gas reserves.

3. BPC (Anadarko) et al Turner Valley 10-16-21-3 W5M (7.45% interest)

This well has been drilled and completed in the gas cap of the Regional Turner Valley oil pool. Production commenced late last year and is reported to now be choked back very significantly to reduce production of 45° – 47° gravity oil.

4. Impact et al Calgary 3-8-22-3 W5M (4.41% carried and working interest)

This well has been drilled into the Turner Valley reservoir. Completion of this well will nullify the need for a well to be drilled at the 6-8-22-3 W5M location.

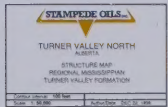
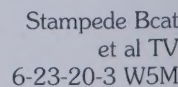
Future Operations

1. Stampede Bcat et al TV 6-23-20-3 W5M (21.25% BPO, 11.69% APO interest)

Subsequent to the commencement of commercial oil production from the Stampede Turner Valley 2-34 well, Stampede plans to initiate a sidetrack operation on the currently suspended 6-23 well in order to complete it up-structure in the Regional Turner Valley oil zone. The well is currently completed with an indicated 38 feet of oil above water. The sidetrack should encounter approximately 90 feet of net oil pay. The operation should only take 3-4 weeks. Production rate will be similar to the 2-34 well.

2. BPC et al Turner Valley 12-35-20-3 W5M (10.65% interest)

Stampede, as operator, plans to take over the existing cased wellbore of this well and sidetrack it into Lsd 16 Sec 32 Twp 20 Rge 3 W5M as a follow-up development well to the current 2-34 well. This well should encounter the Regional Turner Valley oil pool at least 100 feet higher structurally to the offset 2-34 oil discovery well. Oil production rates are expected to be similar to those of the 2-34 well.



3. Stampede et al TV 11-15-21-3 W5M (26.65% interest)

The surface location for this well in 15-15-21-3 W5M is approximately one mile due west of the 8-21 discovery well and the offset 10-16 well surface location. Immediately after the production start-up of the 2-34 well, a new public consultation process is to be conducted followed by an application for drilling license for this well.

4. Stampede Bcat et al TV 7-25-20-3 W5M (28.3% interest)

This well was deepened from the previously suspended total depth in the top of the Regional Turner Valley formation down into and through the base of the underlying Devonian Crossfield member. A maximum thickness of 79.7 m (261 ft.) of Crossfield formation was encountered at this location with approximately 69 m (221 ft.) of net reservoir. The upper 13.66m (45 ft.) which is determined by logs to be gas-bearing, will be production tested this year.

The results of this deepening operation have determined that the underlying Devonian structure is probably a northern extension from the Turner Valley South pool in which the Fortune et al Hartell 4-13-19-2 W5M gas well is located, and that the structure trends north-northeast in the direction of Red Deer Lake.

A gas water contact has been interpreted from the 7-25 deepening for this north pool and it is expected to contain recoverable gas reserves in excess of 2.5 TCF.

TURNER VALLEY SOUTH GAS POOL

1. Fortune et al Hartell 4-13-19-2 W5M (21.25% BPO, 5.3125% APO interest)

The final completion operation preparatory for having this well placed on production was commenced in December, 1998 and completed on February 12, 1999. The well is expected to commence production at a minimum of 5 mmcf of gas per day. A pipeline transportation and gas processing agreement was entered into on January 21, 2000. Stampede and partners entered into a Farmout Agreement with Fortune Energy Inc. whereby Fortune is to pay all costs of tying this well in for production, plus the deepening and completion costs of the offset development well, Fortune et al Hartell 11-12-19-2 W5M. Fortune has entered into a new pipeline agreement for the transmission of gas to the Mazeppa gas plant and this well is expected to finally be on production this year.

2. Fortune et al Hartell 11-12-19-2 W5M (10.625% interest)

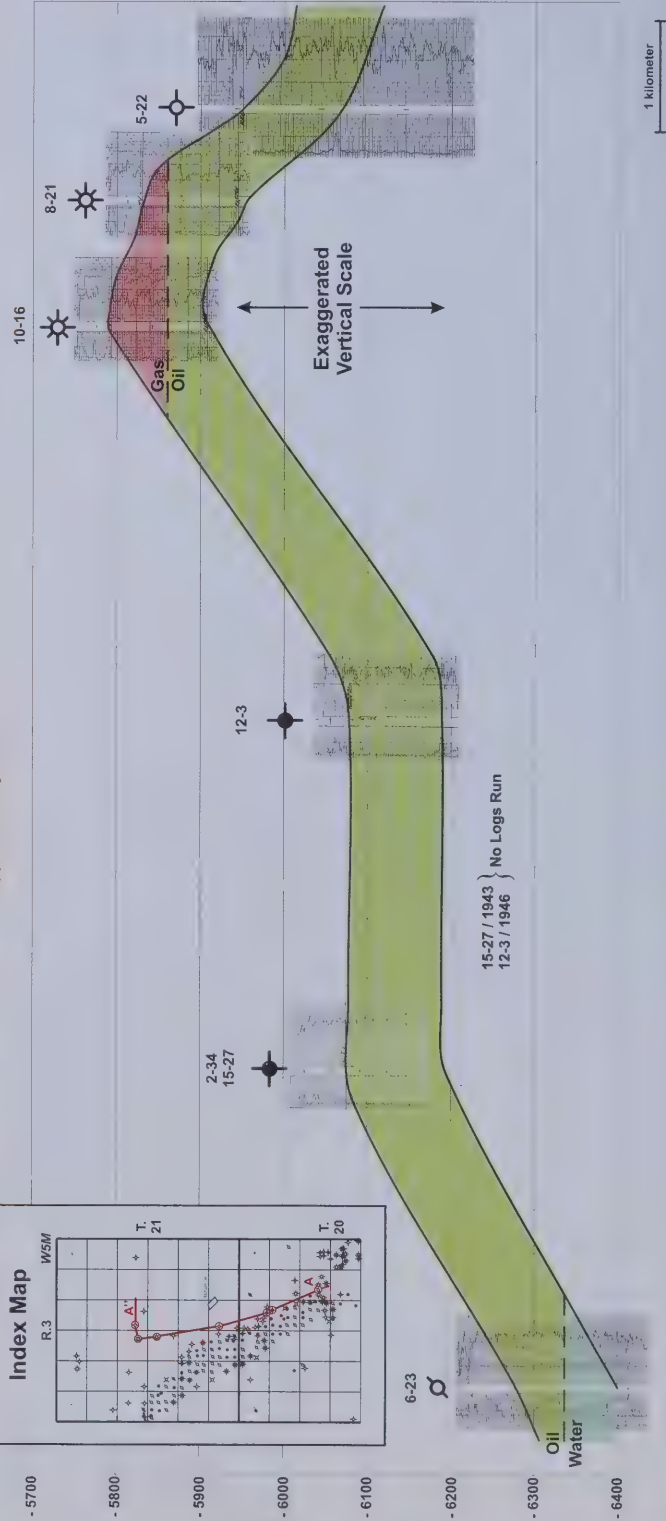
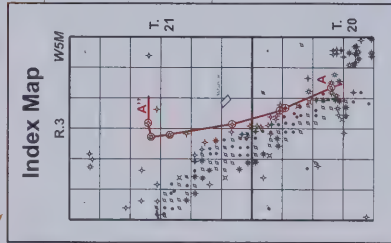
An application for approval to deepen the offset 11-12 well, located across the highway from the 4-13 gas well, has been submitted to the EUB. The 11-12 is currently suspended in the Regional Shunda formation underlying the Regional Turner Valley. This operation is expected to take from two to three weeks and will be completed in a manner which should allow a gas production rate in excess of 10 mmcf per day. The new operator has entered into a new transmission and processing agreement with the successor to Dynegy Midstream Services. This 11-12 deepening should be conducted prior to year end.

TURNER VALLEY CROSS SECTION

A **A''**

Actual Structural Profile (Scale 1 to 1)

Approximately 7.5 miles



RESERVES (as at January 31, 2002)

The total oil and gas assets of Stampede, tabulated from in-house generated and third party determined figures, are summarized as set out below:

GAS	Gross (BCF)		Net (BCF)	
Status	Proven	Proven & Probable	Proven	Proven
Probable				
Producing	0.25	—	0.035	0.050
Shut-in	41.20	—	10.540	466.995
Total	41.45	—	10.575	467.045

OIL	Gross (MSTB)		Net (MSTB)	
Status	Proven	Proven & Probable	Proven	Proven
Probable				
Producing	—	—	—	—
Shut-in	15.55	57.05	3.9	27.85
Total	15.55	57.05	3.9	27.85

BCF = Billion cubic feet of gas

MSTB = One thousand standard tank barrels

Proven Reserves are those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

Proven and Probable Reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future. All probable reserve volumes and associated values have not been adjusted for engineering or geological risk.

PETROLEUM AND NATURAL GAS LEASE INTERESTS

Alberta

Cessford (Central Alberta) — 7.35% net working interest

Reserves	Oil	Status	Shut-in
Reservoir Zone	Glauconite	Gross Acreage	320 acres
No. of Wells	1	Net Acreage	23.5 acres

Kavanagh (Central Alberta) — 25% net working interest

Reserves	Oil and Gas	Status	Shut-in
Zone	Ellerslie-Basal Cretaceous	Gross Acreage	640 acres
No. of Wells	1	Net Acreage	160 acres

Turner Valley (Southwestern Alberta) — 4.41-28.36% net working interest

Reserves	Oil and Gas	Status	Oil - 2 Shut-in, 1 producing
Reservoir Zones	Overthrust and Regional		Gas - 3 Shut-in, 2 producing
	Mississippian and Devonian	Gross Acreage	24,978 acres
No. of Wells	8	Net Acreage	4,256 acres

British Columbia

Grassy (Northeastern British Columbia) — 15% net working interest

Reserves	Gas	Status	Suspended
Reservoir Zone	Mississippian Debolt	Gross Acreage	697.5 acres
No. of Wells	2	Net Acreage	104.6 acres

Petroleum and Natural Gas Acreage	Total Gross	26,635 acres
	Total Net	4,544 acres

McCallum and Company

Chartered Accountants

AUDITOR'S REPORT

To the Shareholders of Stampede Oils Inc.

We have audited the balance sheet of Stampede Oils Inc. as at January 31, 2002 and the statements of loss and deficit and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at January 31, 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

May 30, 2002
Calgary, Alberta

McCallum and Company

McCallum and Company
Chartered Accountants

Balance Sheet

January 31

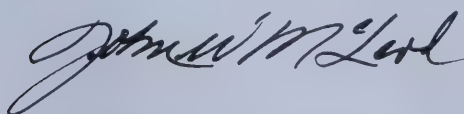
	2002	2001
ASSETS		
Current assets:		
Joint venture and other receivables	\$ 416,310	\$ 322,408
Joint venture receivables		
– related party (Note 3)	2,204,723	1,856,987
Goods and services tax recoverable	174,946	303,202
Marketable securities at estimated market value	39,397	39,397
	2,835,376	2,521,994
Due from related parties (Note 4)	447,636	429,382
Investment in a related party (Note 5)	393,279	1,264,337
Capital assets, at cost (Note 6)	11,035,807	10,860,234
Less accumulated amortization	7,686,575	7,686,120
	3,349,232	3,174,114
	\$ 7,025,523	\$ 7,389,827

LIABILITIES AND SHAREHOLDERS' EQUITY

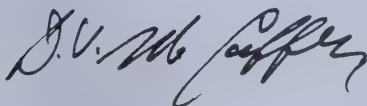
Current liabilities:		
Bank overdraft	\$ 20,238	\$ 48,969
Demand bank loan (Note 7)	90,000	-
Joint venture and other payables	1,974,685	2,673,241
Expenditures to be incurred on behalf of investors (Note 8)	103,166	103,166
Due to related parties	495,232	371,438
Current portion of long-term debt (Note 9)	651,752	597,880
	3,335,073	3,794,694
Long-term debt (Note 9)	2,793,859	2,011,097
Shareholders' equity:		
Share capital (Note 10)	23,669,892	23,045,574
Deficit	(22,773,301)	(21,461,538)
	896,591	1,584,036
	\$ 7,025,523	\$ 7,389,827

Going concern assumption (Note 1)

Approved by the Board:



Director



Director

Statement of Loss and Deficit

	Year ended January 31	
	2002	2001
Revenue:		
Oil and gas revenue, net of royalties	\$ 2,797	\$ —
Interest income	33,055	24,352
	35,852	24,352
Expenses:		
Production costs	14,039	35,387
Audit and legal fees	76,113	10,844
Finance costs	312,649	451,817
General, administrative and operating costs	289,441	288,498
Interest charges	4,860	480
Listing, trustee and agency fees	21,111	22,848
Long-term debt interests (Note 9)	628,947	164,714
Amortization	455	156
Equity reduction in investment in a related party (Note 5)	—	189,244
	1,347,615	1,163,988
Loss for the year	(1,311,763)	(1,139,636)
Deficit, beginning of year	(21,461,538)	(20,321,902)
Deficit, end of year	\$ (22,773,301)	\$ (21,461,538)
Loss per share	\$ (0.02)	\$ (0.02)
Going concern assumption (Note 1)		

Statement of Cash Flows

	Year ended January 31	
	2002	2001
Cash flows used in operating activities:		
Loss for the year	\$ (1,311,763)	\$ (1,139,636)
Adjustments for items not affecting cash:		
Amortization	455	156
Equity reduction in investment in related party (Note 5)	—	189,244
	(1,311,308)	(950,236)
Net changes in non-cash working capital:		
Increase in joint venture and other receivables	(93,902)	(171,599)
Increase in joint venture receivables – related party	(347,736)	(1,448,377)
Decrease (increase) in goods and services tax recoverable	128,256	(247,619)
Increase (decrease) in joint venture and other payables	(698,556)	1,899,933
Decrease in expenditures to be incurred on behalf of investors	—	(120,000)
Increase in due to related parties	123,794	159,101
Increase (decrease) in current portion of long-term debt	53,872	(19,383)
	(834,272)	52,056
	(2,145,580)	(898,180)
Cash flows used in investing:		
Due from related parties (Note 4)	(18,254)	423,234
Oil and gas properties, net proceeds (additions)	(175,573)	(1,442,575)
Investment in related party (Note 5)	871,058	(555,402)
	677,231	(1,574,743)
Cash flows from financing:		
Long-term debt (Note 9)	782,762	1,245,029
Increase in share capital (Note 10)	624,318	1,170,000
	1,407,080	2,415,029
Decrease in cash	(61,269)	(57,894)
Cash (deficiency), beginning of year	(48,969)	8,925
Cash (deficiency), end of year	\$ (110,238)	\$ (48,969)
Going concern assumption (Note 1)		
(Cash includes bank demand loan) (Note 7)		

Notes to the Financial Statements

January 31, 2002

1. GOING CONCERN ASSUMPTION

These financial statements have been prepared on the basis of accounting principles applicable to a "going concern" which assume that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of operations.

As at January 31, 2002, there is a working capital deficiency excluding related parties of \$2,209,188 and the accumulated deficit amounts to \$22,773,301.

The Company's continued existence as a going concern is therefore dependent on the continued ability of management to raise further equity capital to successfully develop Turner Valley Oil and Gas development. (See also Note 9(d))

Because management believes that any possible adverse conditions which may arise will be overcome, these financial statements do not reflect adjustments which would be necessary if the going concern assumption were not appropriate.

If the "going concern" assumption was not appropriate for these financial statements, then adjustments would be necessary in the carrying values of assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) *Oil and gas properties and production equipment*

The Company follows the full cost method of accounting for oil and gas properties as set out in the Canadian Institute of Chartered Accountants' accounting guidelines. All of the Company's properties are in Canada and accordingly, there is one cost centre. Capitalized costs include land acquisition, geological and geophysical expenses and costs of drilling both productive and non-productive wells. Sales of oil and gas properties are recorded as reductions of capitalized costs with no gain or loss being recorded in income, except on significant dispositions. Capitalized costs are depleted by the unit-of-production method based on estimated proven reserves of oil and gas with products being converted to a common unit of measure based on energy content. For purposes of the ceiling test, future net revenues are undiscounted and reduced by future general and administrative expenses and financing costs.

(b) *Mining properties*

Costs of acquisition (including lease and royalty costs) and development of mining properties (including allocated administrative costs) are capitalized on an area of interest basis. On the project being fully developed, amortization of these costs will be on a unit-of-production basis, based on estimated proven reserves of minerals in the area should such reserves be found. No amortization has been recorded to date. If an area of interest is abandoned, the costs related thereto are charged to income in the year of abandonment.

(c) *Office equipment*

Depreciation of office equipment is recorded at a rate of 20% on a straight-line basis.

(d) *Flow-through common shares*

The Company credits the full amount of the proceeds of flow-through shares (which transfers the deductibility of exploration expenses to the investor) to share capital, when such expenditures have been incurred.

(e) *Financial instruments*

Financial instruments of the Company include cash, accounts receivable, substantially all current liabilities and long-term debt. Unless otherwise disclosed, there are no significant differences between the carrying value of these amounts and their estimated fair values.

(f) Measurement uncertainty

The preparation of the financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from and affect results reported in these financial statements.

(g) Marketable securities

Short term investments are carried at the lower of cost and market value.

3. RELATED PARTIES

Though the Company, Bearcat Explorations Ltd., and its subsidiaries, Bearcat Explorations, Inc., Highland Glen Explorations Limited and Lumberton Mines Limited are related parties in that they have common management, Stampede Oils Inc. has a distinct difference in its Board of Directors and Shareholder make-up relative to the above mentioned companies and is subject to a separate corporate control set up. Oil and gas and mining operations are in joint venture with these companies.

4. DUE FROM RELATED PARTIES AND RELATED PARTY TRANSACTIONS

	Year Ended January 31	
	2002	2001
Due from Highland Glen Explorations Limited	\$ 64,155	\$ 64,155
Loans to a director and officer including interest	322,500	304,246
Due from Lumberton Mines Limited	60,981	60,981
	\$447,636	\$ 429,382

(a) Advances to Highland Glen Explorations Limited

This receivable bears no interest and has no specific terms of repayment. Ultimate failure to repay these advances will result in 350,000 Class A shares of Stampede Oils Inc. reverting back to the Company as full settlement.

(b) Loans to a Director and Officer

The Company advanced these funds to its President, John W. McLeod, to provide for and ensure his participation in the Company's Rights and Warrants offering. These secured loans bear interest at 6% per annum and as amended by Director's minutes become due and payable June 8, 2004.

(c) Advances to Lumberton Mines Limited

These advances bear no interest and have no specific terms of repayment. By way of a Letter Agreement dated October 15, 1991, Lumberton Mines Limited acquired the Company's working interest in the Grassy North P & NG lease by assuming the obligations and expenditures incurred by the Company with respect to that drilling program.

5. INVESTMENT IN BEARCAT EXPLORATIONS LTD.

	Year Ended January 31	
	2002	2001
Investment, at cost less impairment	\$393,279	\$1,264,337
The investment consists of 3,202,814 (2001 – 10,296,597) common shares representing a 4% equity interest in Bearcat Explorations Ltd. (2001 – 12.9%).		

The assets and operations of Bearcat Explorations Ltd. consists substantially of interests in the same oil and gas and mining properties in which this Company also holds interests.

	Year Ended January 31	
	2002	2001
Equity reduction of investment	—0—	\$ 189,244

6. CAPITAL ASSETS

(a) Summary

	Cost	Accumulated Amortization	Net Book Value January 31	
			2002	2001
Oil and gas assets	\$11,029,383	\$7,681,970	\$3,347,413	\$3,173,488
Office equipment	6,424	4,605	1,819	626
	\$11,035,807	\$7,686,575	\$3,349,232	\$3,174,114

(b) Turner Valley Project

To January 31, 2002, the Company has participated directly in eight exploratory wells in the Turner Valley area of Alberta. Testing of three of these wells has determined the discovery of substantial natural gas reserves and indications of possible significant oil reserves; however, for accounting purposes, some of these reserves are classified as proved undeveloped pending further testing completion of production and drilling of additional and existing wells necessary to validate the overall reserve assumptions and to establish sufficient productivity parameters with which to justify the expenditures required to install producing and gathering facilities.

(c) Ceiling Test

The Company used year-end prices for oil and natural gas when calculating the ceiling test. Full cost accounting guidelines exclude substantial probable reserves. Management is confident that such reserves will ultimately be established as proven.

7. BANK FINANCING

The demand bank loan bears interest at prime plus 1%. As collateral the Company provided a General Security Agreement. This bank loan was retired on February 21, 2002.

8. EXPENDITURES TO BE INCURRED ON BEHALF OF INVESTORS

The Company has received funds from investors to incur expenditures qualifying as Canadian Exploration Expense or Canadian Development Expense as these terms are defined in the Income Tax Act. All rights, titles, benefits and interest in any mineral interest resulting from these expenditures accrue to the Company. Income tax deductions relating to these expenditures flow through to the investors. Remaining funds to be expensed at January 31, 2002 amounted to \$103,166.

9. LOANS FROM PRIVATE INDIVIDUALS

		Year Ended January 31	
		2002	2001
(a)	Loans jointly to the Corporation and Bearcat Explorations Ltd. in the aggregate amount of \$675,000 allocated to the Corporation:	\$ 651,752	\$ 597,880
	Terms:		
	– Secured by a registrable first mortgage instrument over specific oil and gas properties.		
	– Specific repayment procedures based on future revenues.		
	– Bearing interest at Royal Bank of Canada, prime plus 2%.		
	– The corporation is contingently liable with respect to advances made to Bearcat Explorations Ltd. under this loan.		
(b)	Loan jointly to the Corporation and Bearcat Explorations Ltd. (the Borrowers) in the aggregate amount of US \$3,393,364:		
	Allocated to the Corporation (CDN)	2,793,859	2,011,097
	Per a proposed agreement to be effective August 3, 2001, the following terms were negotiated:		
	– A company owned by the lender will received additional carried working interest as is required to make that company's interest equal to 15% of the borrowers, as well as a 3% gross overriding royalty.		
	– Interest to be calculated at 1% per month, calculated and compounded monthly until August 11, 2002 and thereafter at 2% per month.		
	– Existing indebtedness is due in full on demand made after August 11, 2002.		
	– Repayment terms to be based on future oil and gas production revenue.		
	– Security is to include a general security agreement.		
	– Option agreement requiring the borrowers to acquire a working interest for \$10,330,092. Post principal repayment.		
	– As further consideration for loan financing, 100% of Panda Petroleums Ltd. was assigned to lender.		
		3,445,611	2,608,977
	Less estimated current portion	651,752	597,880
		\$ 2,793,859	\$ 2,011,097

10. SHARE CAPITAL

(a) Authorized

Unlimited number of Class A voting common shares without nominal or par value

Unlimited number of Class B non-voting common shares without nominal or par value

Preferred convertible shares, Series A, non-voting and limited in number to 1,440,000 shares

(b) Issued

	January 31, 2002		January 31, 2001	
	Number of Cost	Issuance	Number of Cost	Issuance
Shares:				
Class A common voting shares				
Beginning of year	62,143,514	\$23,045,574	51,643,514	\$21,875,574
Private placement financing:				
Bearcat Explorations Ltd.	—	—	5,229,840	522,984
Other - Flow through shares	3,619,049	732,000	5,270,160	527,016
Flow through shares, expenditures incurred	—	—	—	120,000
Issuance costs	—	(110,182)	—	—
Employee stock option plan	25,000	2,500	—	—
	65,787,563	\$23,669,892	62,143,514	\$23,045,574

(c) Stock Options

Stock options for the issuance of 5,300,000 Class A common voting shares have been granted to Directors, Officers and a consultant of the Company. These stock options expire as follows:

	Number of Class A Shares	Exercise Price
October 27, 2004	4,850,000	\$0.10
March 13, 2007	450,000	\$0.17

(d) Subsequent events

(a) On February 4, 2002, a director acquired 100,000 Class A shares at \$0.10 per share per the stock option plan.

(b) On February 14, 2002, 400,000 Class A shares were issued at \$0.18 per share.

11. SEGMENTED INFORMATION

The Company operates totally within Canada, in the oil and gas industry and the mining industry.

12. INCOME TAX

The company has accumulated non-capital losses for income tax purposes of approximately \$2,900,000 of which no benefit has been recorded in these financial statements. These losses expire as follows:

2003	365,000
2004	324,000
2005	345,000
2006	305,000
2007	371,000
2009	1,190,000

In addition resource pools of approximately \$9,120,000 exist. No benefits with respect to the above have been included in these financial statements.

Corporate Information

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website: <http://www.stampede.ab.ca>

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J.W. McLeod - President
M.J.S. Hunt - Treasurer
P.A. de Bruycker - Secretary

Directors:

R.E. Cochrane
P.A. de Bruycker
R.B. Furukawa*
J. E. Hawthorne
C.B. Locke
D.V. McCaffery*
J.W. McLeod*

*Audit Committee

Auditors:

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Calgary, AB T2P 3T7

Transfer Agent & Registrar:

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Stock Exchange & Trading Symbol:

Canadian Venture Exchange - STF



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